Utah Renewable Energy Initiative Workgroup

PacifiCorp Avoided Costs
August 1, 2007

Presented by Becky Wilson
Executive Staff Director
Utah Public Service Commission

Presentation Outline

- Background and context for understanding the calculation of avoided utility costs of PacifiCorp, dba in Utah as Rocky Mountain Power Company.
- Definition of Avoided Cost
- Avoided Cost Calculations

Utah Public Service Commission

- Created in 1917 to regulate retail utility services offered by private companies known as “public utilities”.
- Public utilities are granted a franchise and in return must serve all requests for service at rates, terms and conditions set by the Utah Public Service Commission (PSC or Commission).
- Service must be adequate; rates, terms and conditions of service must be just and reasonable.

Utah Public Service Commission

- Performs as a quasi-judicial entity.
- “Views” on issues are provided as “decisions” through written orders and rules. Decisions have the effect of law.
- Decisions are issued in response to a public proceeding.

Utah Public Service Commission

- Regulates PacifiCorp dba Rocky Mountain Power.
  - PacifiCorp operates a utility system of generation, transmission and distribution plant located throughout the west and serves retail customers in six states.
  - This utility system provides about 75-80% of the electricity in Utah.
- No authority over municipal power utilities and limited authority over electric power cooperatives.

Utah Public Service Commission
State Law and Regulations

- Planning: USC 54-1-10, PSC shall engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources.

- Planning: 1992 PSC Order on Integrated Resource Planning (IRP) requires PacifiCorp to evaluate all feasible alternatives on a consistent and comparable basis and to account for future risks and uncertainties to find the lowest long-run cost to meet growing consumer demand.

Qualifying Facilities

- Created by Congress in 1978 (PURPA) to encourage efficient and clean sources of domestic electricity generation. State also included language encouraging “independent power producers” defined as:
  - Cogeneration projects.
  - Small power production plant, i.e., biomass, waste, renewable resources and geothermal resources, 80 megawatts or less.
- Public utilities must purchase QF power.
- Price, terms and conditions set by PSC.
- Price must be set at utility’s full avoided cost.

PURPA Defines Avoided Cost

- “The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.”
- State has similar definition. UCA 54-2-1(1)

Standard Rates for Small QFs in Utah

- For small power production plants less than 3 MW and cogeneration plants less than 1 MW, the PSC has approved Rocky Mountain Power Rate Schedule No. 37 prices, terms and conditions.

- http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2286.pdf

Standard Rates for Small QFs

- Rates are based on the difference between two production dispatch model runs in the short run and the capital and operating cost of an IRP resource in the long-run.
- Rates are currently based on IRP 2004 Update and the IRP proxy plants avoided are coal (Hunter 4) and natural gas (CCCT) in 2012.
- Rates are updated when conditions change or new IRP resources are identified.
- These rates also form the basis for payments to net metering customers for excess power generated and supplied to the utility.

Standard Rates for Small QFs

- The volumetric price in 2007 is between 4.3 and 5.4 cents per kilowatt hour depending on time of day and time of year.
- Alternatively, a QF may be paid a fixed price per kilowatt of capacity, $3.12 per kilowatt-month, and an energy rate, 4.4 cents, per delivered energy in 2007.
- Under either payment approach, the QF may elect year by year pricing or a levelized-price that stays constant for the duration of the contract.
- A 20-year contract beginning 2007, assuming the QF has an 85% capacity factor, has a levelized price of $52.71 per megawatt hour.

Rates for QFs larger than Schedule 37

- PSC has approved Rocky Mountain Power Schedule No. 38 procedures for obtaining indicative pricing and a power purchase contract.

- http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule28325.pdf

Rates for QFs under Schedule 38

- Applicable for projects up to 99 MW
- Current indicative rate per MWh, levelized, for 20-year contract 2007-2026 is:
  - $54.03 for a cogeneration project, assuming an 85% CF
  - $57.76 for a wind project
- Rates for non-wind projects based on IRP resources and partial displacement differential revenue requirements method.
- Rates for wind projects based on last competitively negotiated wind project price.

Other Avoided Cost Methods

- Utility avoided costs for demand side management options.
  - IRP Load Decrements
  - Market Price Estimates

Load Decrement Method

- Assumes IRP 2007 Preferred Portfolio.
- Calculates reduced system operating cost of various types of energy efficiency.
- Energy efficiency programs modeled as contracts that supply energy according to hourly load shapes. These contracts serve as surrogates for direct load reductions attributable to programs.

Load Decrement Method (cont.)

- An hourly production cost model is run twice in stochastic mode with and without the energy efficiency programs. The difference in the two runs provides the change in system cost (reduction in the stochastic mean present value of revenue requirements for 100 simulations) from lower market purchases or resource re-optimization due to the addition of the energy efficiency programs.

Figure 25. Rocky Mountain Power Territory Annual IRP Decrement and Market Price Values

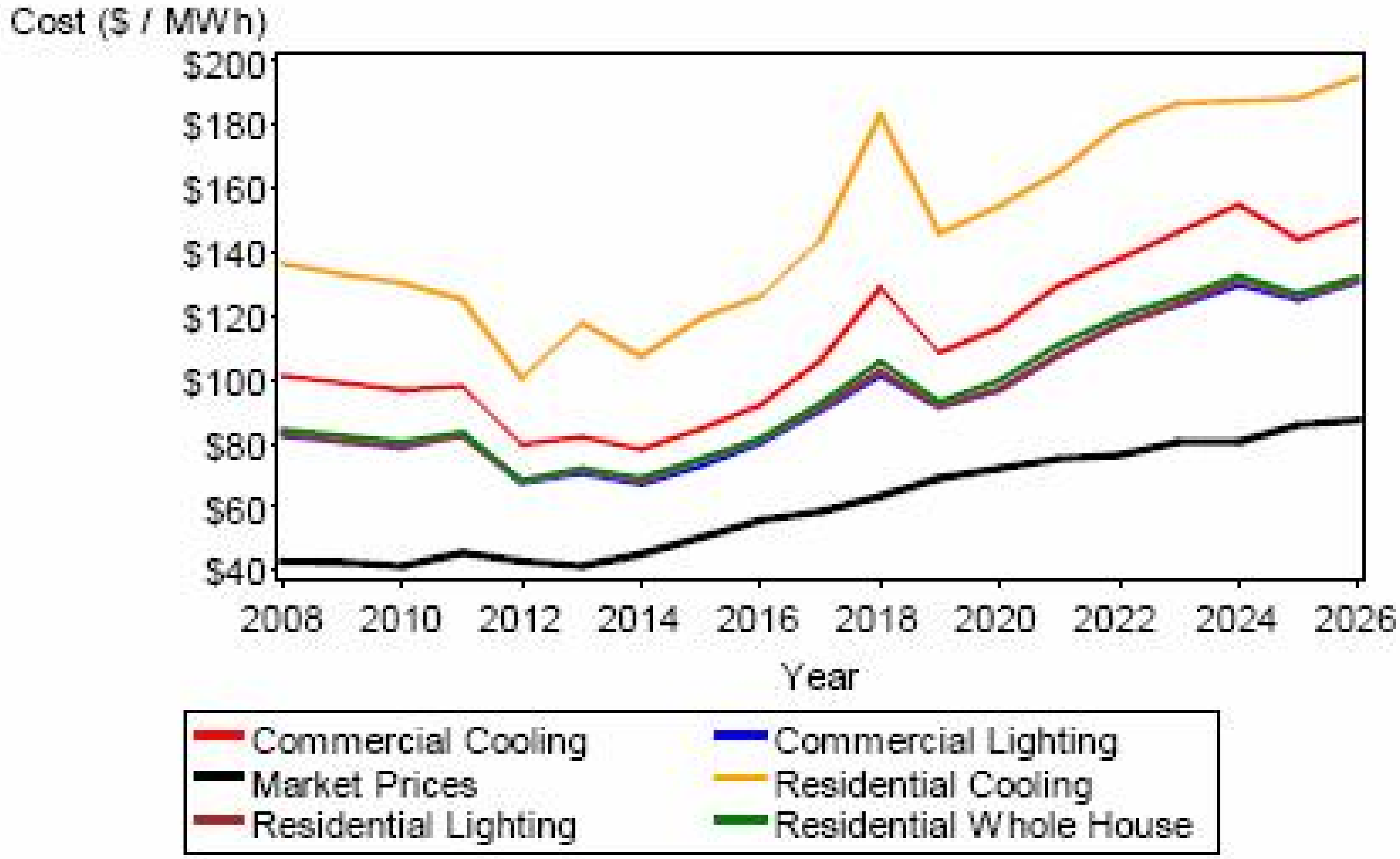

Table 7.47 – Annual Nominal Avoided Costs for Decrements, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	113.38	108.78	87.59	102.59	93.54	103.99	109.84	125.48
Residential Lighting	60%	68.98	71.73	59.68	62.57	59.64	64.99	70.69	79.62
Residential Whole House	46%	70.15	72.66	59.42	62.88	60.20	65.45	70.96	80.75
Commercial Cooling	16%	84.24	85.30	69.27	71.34	67.94	73.62	80.28	92.47
Commercial Lighting	49%	68.54	71.97	58.73	61.46	58.68	63.41	69.75	78.65
System Load Shape	65%	65.18	68.16	56.32	59.07	56.47	61.24	67.18	75.95
WEST									
Residential Cooling	20%	53.78	51.87	46.99	48.02	53.67	61.06	64.64	71.75
Residential Heating	28%	39.61	51.06	46.11	41.06	46.09	49.83	58.15	62.73
Residential Lighting	60%	44.34	48.56	43.70	42.10	47.45	52.78	58.20	64.16
Commercial Cooling	16%	51.66	51.53	46.13	45.39	50.85	56.96	61.81	68.73
Commercial Lighting	49%	43.70	49.34	44.49	42.02	47.47	53.32	59.31	64.67
System Load Shape	67%	43.30	47.26	42.03	40.37	45.83	50.94	56.26	61.72

Current Activity

- Comments on IRP 2007 due August 31.
- Commission has ordered a review of cost-effectiveness test inputs and assumptions.
- Rocky Mountain Power, Division, Demand side Advisory Group directed to report back recommendations.

Questions?